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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U 39-E) for Approval of Demand Response Programs, Pilots and Budgets for Program Years 2018-2022.	Application 17-01-012 (Filed January 17, 2017)
And Related Matters.	Application 17-01-018 Application 17-01-019

PACIFIC GAS AND ELECTRIC COMPANY'S (U39E) RESPONSES TO ADMINISTRATIVE LAW JUDGES' RULING REQUESTING RESPONSES TO QUESTIONS

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Pacific Gas and Electric Company (PG&E) submits herein its responses to the "*Administrative Law Judges' Ruling Requesting Responses to Questions*" issued on June 15, 2018.

I. DEMAND RESPONSE PILOT TO BENEFIT DISADVANTAGED COMMUNITIES.

1. Comment on the merits of the Proposal, explaining your rationale.

PG&E believes there is merit in conducting Disadvantaged Communities (DAC) pilots testing approaches that can inform "new" Demand Response (DR) programs focused on reducing dispatch of fossil fueled power generation facilities located in or near DACs. A well-constructed pilot program could provide useful information to the Commission and DR program providers on "new" DR program design and operation. As part of the DAC DR pilot, PG&E is interested in better understanding how the inventory of flexible load that can receive and respond to DR signals can be identified and engaged by a DR program. PG&E is also interested in exploring the potential to cost-effectively expand the inventory of flexible load that can receive and respond to DR signals.

2. What changes or clarifications, if any, would you recommend and why?

PG&E recommends that the Commission engage in discussions with the CAISO prior to finalizing the DAC DR Pilot guidance document to better understand the relationship between energy consumption within a DAC or aggregation of DACs and dispatch of fossil fueled generation facilities that are located in or near those DACs. PG&E is not convinced that, even at scale, load reductions within a DAC or aggregation of DACs will materially impact the dispatch of generation facilities in or near those DACs.

PG&E believes that a CAISO Local Capacity Area (LCA) would be the best choice for a DAC DR Pilot (See Figure 1 for a map of the LCAs statewide). Load within an LCA is sufficiently large so that program impacts, at scale, could influence dispatch of generation units on the margin. Demand response resources can currently be identified and called by LCA but not by individual DACs or aggregations of DACs.

Subject to Commission approval, PG&E is considering developing its DAC DR Pilot to target load reductions in one or more of the following LCAs: Stockton, Greater Fresno, Kern, Greater Bay Area. PG&E believes that targeting load reduction by LCA will provide the most relevant and scalable information with respect to development of new DR programs focused on reducing dispatch of fossil fueled generation facilities located in or near DACs.

Figure 1 – Local Capacity Area Map

The San Joaquin Valley area which spans the Stockton, Fresno, and Kern LCAs has a high concentration of both DACs and fossil fueled fired power generation facilities. Based on feedback from stakeholders during the DAC DR Workshop held on February 15, 2018, in addition to a DAC DR Pilot targeted in the San Joaquin Valley Air Basin, PG&E is also considering designing a DAC DR Pilot focused on the Greater Bay Area LCA which also has some DACs and some fossil fueled generation facilities. As discussed at the DAC DR Pilot workshop, the end-uses driving peak loads and customer demographics in the Greater Bay Area may be different than in the San Joaquin Valley. Developing DAC DR Pilots across both locations may provide useful information for future program development.

3. Do you agree or disagree with the proposed definition of disadvantaged communities? Explain your reasoning.

As stated in PG&E's responses to the Straw Proposal submitted on February 29, 2018, PG&E agrees that using the SB 535 definition for DACs, which is consistent with the proposed definition for the Integrated Resource Planning (IRP) proceeding,[1] will increase the relevance and transferability of data analysis and recommendations.

4. Comment on the adequacy of proposed requirements for disadvantaged communities demand response pilot plans listed under Section II of the Proposal.

PG&E believes the proposed requirements for the DAC DR Pilot are reasonable.

5. Do you agree or disagree with the purpose and goal of disadvantaged communities demand response pilots stated in the Proposal? Explain your reasoning.

As stated in response to Question 1, above, PG&E believes there is merit in conducting pilots testing approaches that can inform "new" DR programs focused on reducing dispatch of fossil fueled generation facilities located in or near DACs. If such pilots are successful and scalable they will have the desired effect of providing useful information to the Commission. As part of the DAC DR pilot, PG&E is interested in better understanding how the inventory of flexible load that can receive and respond to DR signals can be identified and engaged by a DR program. PG&E is also interested in exploring the potential to cost-effectively expand the inventory of flexible load that can receive and respond to DR signals.

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[1] *See,* California Public Utilities Commission, *Assigned Commissioner's Office Proposal for Demand Response Pilot Plans to Benefit Disadvantaged Communities*, June 2018, p 3.

6. **Do you agree or disagree with "adopting the method and initial set of candidate locations within each utility service territory proposed by Olivine, as the starting point for selecting pilot locations"? Explain your reasoning.**

As explained in the response to Question 2, above, PG&E believes that targeting one or more of the San Joaquin Valley area LCAs (Stockton, Greater Fresno, Kern) and the Greater Bay Area LCAs will likely provide the most useful data that can inform "new" models of DR that are focused on reducing the dispatch of fossil fueled generation facilities located in or near DACs. Load reductions, even at scale, within individual DACs or aggregations of DACs are unlikely to be sufficient to impact the dispatch of fossil fueled generation facilities in or near the DAC(s). For example, PG&E's Huron substation observed peak load in 2017 was approximately 7.5 MW. Load reductions from DR of 5% would represent only 375 KW which would likely not be enough to impact the dispatch of fossil fueled generation units in or near the city of Huron. By comparison peak load in the Greater Fresno LCA, which includes the city of Huron, is approximately 3,250 MW so a 5% reduction in peak load responding to a DR event would be approximately 165 MW which may be significant enough to impact dispatch of marginal gas fired units in or near Huron and other DACs within the Greater Fresno LCA.

7. **The Proposal notes, "Pilot objectives should . . . focus on identifying a few test objectives in order to maximize both the quantitative value of the results . . . and qualitative value of results to inform policy recommendations.'' What key objective do you recommend testing, with which strategy and customer segment, and why? (e.g. objective of increasing enrollment and participation of residential customers in DACs, through a community based outreach program strategy.)**

PG&E believes testing the following key objectives through a pilot will help inform "new" models of DR that are focused on reducing dispatch of fossil fueled generation resources. These new models of DR can go beyond load shed and potentially include environmental elements:

a. Test the ability of IOUs and third-party DR providers to develop programs that can effectively respond to a continuously streaming signal indicating air emissions intensity in a LCA.

- For example, test whether IOUs and third-party DR providers can develop programs that respond to a LCA specific air emissions intensity signal similar to the systemwide WattTime GHG intensity signal currently proposed for use in the SGIP program to support environmentally sustainable operation of battery energy storage devices.
- Test whether customer interest/engagement increases when the messaging is localized and based on social benefits rather than or in addition to individual monetary benefits.

b. Test customer receptiveness to "new" DR types of program that are automated, called frequently and have short-duration events.

  - For example, test whether customers are receptive to an automated DR program that has four 15-minute events in a day or ten 5-minute events in a day. WattTime via an applet supported by If This Then That (IFTTT) is currently testing what they call *Environmental Demand Response (EDR).* Currently EDR is targeted toward smart plugs and EV chargers. Participating smart devices receive a streaming signal throughout the day indicating the GHG intensity of generation. Devices respond to multiple events during a day with durations of 5 to 15 minutes. A reasonable goal of the DAC DR Pilot would be to assess how receptive customers are to this type of new DR program offering.
  - A reasonable goal of the pilot could also be to test whether targeted end-uses could be expanded to other appliances such as refrigerators, water heaters or HVAC systems to utilize the thermal storage/flexible load capabilities associated with those appliances or whether this type of program can successfully engage home or commercial battery energy storage systems.

II. DUAL PARTICIPATION

1. (For third-party providers only)

N/A for PG&E

2. (For SCE, PG&E, and SDG&E only) Provide the statistics from the past three years regarding the number of customers you dis-enrolled from the Critical Peak Pricing program because the customers had been registered in a third-party demand response provider program.

The number of customers dis-enrolled from PG&E's Peak Day Pricing program, per Section C.2.d of Electric Rule 24 (Rule 24) and Ordering Paragraph (OP) 3 of Decision (D.) 13-12-029, is listed in the table below:

Year	Number
2016	12
2017	33
2018	1
Total	46

PG&E notes here that it is in the process of re-examining the value of continuing its Peak Day Pricing program in light of increasing disenrollment due to customer opt-outs, disenrollments and migration of customers from PG&E bundled service to non-PG&E energy procurement combined with the shift to evening peak TOU periods.

3. (For SCE only)

N/A for PG&E

4. (For PG&E and SDG&E only) Do you utilize a capping approach for dually participating customers? Explain the approach. If you do not use a capping approach, what method do you use to avoid double payments? Explain why these methods can or cannot be applied to third-party demand response provider programs?

No, PG&E does not utilize a cap for dually participating customers. See the response to question 5, below, regarding the method for avoiding double payments.

5. (For SCE, PG&E, and SDG&E only) How do you avoid double counting for customers that participate in two programs? Explain why this method can or cannot be applied to third-party demand response provider programs?

To avoid double counting the load impacts, whenever there are overlapping events between the PG&E's LMDR (load modifying DR) designated Energy Programs (PDP and Smart

Rate) and PG&E's SRDR (supply resource DR) designated Capacity Programs (BIP and SmartAC) the load impacts are attributed only to the SRDR capacity programs and removed from the LMDR energy programs.

Double payment is not a factor for these programs as the SRDR capacity program only compensates with a capacity payment (BIP) and one-time enrollment incentive (SmartAC). There is no additional compensation for customers participation in events, and market revenues that PG&E receives for these programs are returned to ratepayers.[2]

This method cannot be applied to third-party demand response provider programs because third-party DR program providers have no requirement to provide information to PG&E's Demand Response program administration staff sufficient for PG&E to perform these calculations.

6. What approach would you recommend to allow for the visibility needed by the Utilities regarding what is bid and awarded into the CAISO market while ensuring that customer choices are not decreased? Describe the approach and explain how the approach fulfills both needs. Provide cost estimates for this approach.

PG&E recommends that the Commission in conjunction with the CAISO and DR Stakeholders establish a process by which the many issues related to this topic can be surfaced and resolved. The Commission will also need to decide on at least four key areas of policy:

a. Exemption from the dual participation rules for Rule 24 participants to absolve the need to maintain the one capacity program/one energy program rule and the one day-ahead notification/one day-of notification rule, and to allow double payment for the same load reduction.[3]

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[2] PG&E's Capacity Bidding Program (CBP) offers both a capacity payment and an energy payment, but it may not dual participate with either LMDR energy program.

[3] A DRAM-based exemption may not be sufficient as a process would need to be in place for before and after the DRAM contract delivery period. DRAM customers are typically enrolled in a third-party DRP program via Rule 24 processes at least 60 days prior to the delivery (or showing) month. See the response for question 7 for additional details.

b. Approval to substantively modify the DRAM contract based on the changes decided in the stakeholder process, including visibility into, but not limited to, program design, incentive structure, and dispatches.
c. Approval to substantively modify Rule 24 to remove the firewall and allow dual participation with CPP.

Once the Commission is able to resolve key policy issues outlined above then the remaining tasks are to:

a. Establish the information needed and process by which the information will be exchanged in order to accurately characterize the load impacts related to participants who are dually enrolled and concurrently participating in IOU and non-IOU demand response programs. These characterizations form the basis for DR qualifying capacity estimates used in RA accounting.
b. Establish the information needed and process by which that information will be exchanged in order to accurately settle with participants who are concurrently participating in IOU and non-IOU demand response programs. For example, what information is needed in order to properly characterize the baseline usage patterns for customer who are dually enrolled and concurrently participate in IOU and non-IOU programs.
c. Resolve any remaining issues regarding multiple-use application (MUA) rules and dual participation rules.

PG&E cannot provide any cost estimates until the minimum viable criteria for meeting the key objectives outlined above have been agreed to by stakeholders.

7. What changes to Rule 24/32 do you recommend to allow dual participation between Critical Peak Pricing and a third-party demand response provider program? Justify why these changes are needed. What changes, if any, do you recommend to address the firewall issue described in Section C.1.a.(3) of Rule 24/32? Justify why these changes are needed.

First, PG&E reiterates the comments made at the February 13, 2018 workshop that, for PG&E, the impact on customer choice related to the current prohibition on dual participation between CPP and third-party DR programs may be very small. For example, in response to Duel Participation question 2, above, PG&E's records show that YTD 2018 only 1 customer has been dis-enrolled in PDP in order that the customer could enroll in a third-party DR program. Secondly, for third-party programs procured via the DRAM, the IOUs provides a capacity payment and the CAISO provides an energy payment. In effect, allowing dual participation between third-party DR programs procured via the DRAM and CPP programs would violate the one capacity program and one energy program rule. For the above reasons, PG&E does not support allowing dual participation between Rule 24/DRAM and CPP programs.

With respect to the firewall issues described in Rule 24 Section C.1.a.3, PG&E does not see a way to both keep the firewall in place and allow for dual participation. As long as the firewall is in place, the information required to accurately assess the load impacts related to customers who dually participate in IOU and third-party programs, which is needed for determining load impacts, the RA value, short-term forecasts, and for settlements purposes, will remain unavailable. PG&E recommends that, if the Commission feels strongly that dual participation should be allowed, the Commission should consider eliminating the firewall and instead institute a statement of principle that IOUs can use the information submitted by third-party program providers exclusively for the purpose of determining load impacts and settlements related to dual participation and are prohibited from using the information provided for any other purposes without explicit permission from the third-party program provider or authorization from the Commission.

Rule 24 Section C.2.d on dual participation would also need to be modified to allow for dual participation between third party DRP programs and CPP programs. As all DRAM Sellers are DRPs who utilize Rule 24 processes and systems before, during, and after a DRAM contract delivery period, Rule 24 would need to permit the dual participation with CPP programs. Rule 24 would need to be exempted from the dual participation rules allowing dual participation only between one capacity program and one energy program, and one program with day-ahead notification and one program with day-of notification. Participation in the CAISO markets functions as an energy program in and of itself, so to the extent that third party DRPs have the right to keep revenues from CAISO market participation, dual participation with CPP programs would constitute dual participation with two energy programs and therefore double payment. PG&E would also not be able to ensure notifications would only be day-of, which would be necessary to meet the one day-ahead notification and one day-of notification rule.

In addition to the dual participation rules, Rule 24 would need to reflect that it is the third party DRP's responsibility to properly adjust for the CPP events and exclude CPP event days from the baseline and settlement calculations.

III. AUTOMATED DEMAND RESPONSE INCENTIVE POLICY

1. Do you agree with the matrix provided by the Utilities (See Attachment B.) Explain any disagreement.

PG&E agrees with the matrix provided by the three IOUs, the information reflects existing ADR Program design.

2. Do you agree with the definition of an Auto Demand Response control, as developed during the workshop. Explain any disagreement.

PG&E recommends the following edit to the definition of an Auto Demand Response (ADR) control since the term "current model of demand response" was not defined at the workshop:

> *"the ability to receive an automated demand response signal to enable the customer to participate in a demand response event ~~for current models of demand response~~ without any manual customer intervention."*

3. Explain why you do or do not agree with the following criteria for controls eligible for auto demand response incentives:

a) In the case of all three classes of customers (residential, commercial & industrial, and small & medium businesses) the control must be able to receive an Open Auto Demand Response compliant Auto Demand Response signal;

PG&E recommends the following edits to criteria "a":

a-1) In the case of large non-residential customers, the ADR control on site must be OpenADR 2.0 a or b certified. For PG&E, large non -residential customers are defined as commercial, industrial and ag customers with 500 kW or more average summer peak demand.

a-2) In the case of residential and small & medium business customers, the ADR control can be either on site or at the manufacturer cloud level, and the control must be OpenADR 2.0 a or b certified. Small and Medium Businesses are defined as non-residential customers with 499 kW or less average summer peak demand.

PG&E substituted the word "compliant" with "certified" in its proposed edits above to be consistent with the new 2019 Title 24 code which requires ADR controls to be *certified* with the OpenADR 2.0 standard. PG&E believes the IOUs' ADR programs should have the same requirements as the 2019 Title 24 to avoid potential market confusion.

b) For commercial and industrial customers, the customer must also be able to provide the anticipated kilowatts expected from the end uses equipped with the control as that is what determines the calculated incentive for that class of customers; and

PG&E recommends the following edits to criteria "b":

b) For non-residential customers, the utility performs engineering calculations to develop the estimated kW of load reduction for each ADR project in order to determine the calculated ADR incentive.

c) In the case of the small & medium business customer class and residential customers receiving incentives for thermostats, the criteria depend upon the type of Auto Demand Response in which the customer is enrolled, deemed incentive based on the average kW load drop for that control in that sector.

PG&E recommends the following edits to criteria "c":

c-1) For small to medium office and retail business customers, PG&E's ADR FastTrack Program offers a streamlined application process with the following key elements:

- Pre-approved HVAC and lighting DR strategies
- Pre-calculated incentives for these pre-approved DR strategies
- A simple FastTrack Project Calculation Form

c-2) In the case of residential customers, the utility performs engineering calculations to develop the estimated kW of load reduction for each ADR end use in order to determine the deemed ADR incentive.

4. In the case of incentive eligible thermostats, what policy could encourage manufacturers to equip the controls with easy-to-use time-based functions to help a small business or residential customer respond automatically to time of use rates either while they participate in an event-based program that is eligible for Auto Demand Response incentives, after they leave that program, or both?

PG&E understands that most smart thermostats currently have this functionality ("easy-to-use time-based functions"), and vendors have the ability to easily create pre-programmed algorithms to control heating and cooling, and/or they offer customers the ability to program the devices on their own. Therefore, instituting a policy requiring manufacturers to pre-program devices with specific time-based algorithms may be unnecessary. Before establishing a new ADR-specific policy that is targeted to smart thermostats, PG&E suggests that the CPUC await the results of the IDSM initiatives recently ordered in the EE Business Plan, which directs the IOUs to test and deploy residential automated HVAC technologies for new time-varying rates.

5. Should a base interruptible program (a reliability program) customer bidding into the demand response auction mechanism pilot as a Reliability Demand Response Resource be eligible for Auto Demand Response control incentives? (This question is only asked in terms of the pilot and not in terms of whether the pilot becomes a permanent mechanism; that question is premature.)

PG&E would like to clarify that a customer participating in PG&E's Base Interruptible Program (BIP) must be bid into the wholesale market as a Reliability Demand Response Resource (RDRR), and that a Demand Response Provider (DRP) can receive a Demand Response Auction Mechanism (DRAM) award as a Reliability Demand Response Resource (RDRR); however, in compliance with DR Dual Participation rules a customer cannot participate in both BIP and DRAM (i.e. two capacity programs)

In Decision (D.) 16-02-029, the Commission established that PG&E's BIP customers are not eligible for ADR incentives. Given that a customer could be registered within a Reliability Demand Response Resource (RDRR) via BIP or DRAM, PG&E believes that ADR-eligibility should not be determined solely by whether the Demand Response Provider is an IOU or a third party. PG&E believes that ADR eligibility rules should be consistent, whether all RDRR were to be eligible, or ineligible. However, given that the CPUC has already ruled that a customer registered in a RDRR via an IOU program is not eligible for ADR incentives, PG&E believes that a customer registered in a RDRR via a third party also should not be eligible for ADR incentives.

6. Should the Cost Causation Principle apply to Auto Demand Response incentives; i.e., if a Community Choice Aggregator or a Direct Access energy service provider offers auto demand response incentives to their customers does this qualify as a "similar" demand response program?

PG&E's position has been that the Cost Causation (CC) Principle should not apply to ADR because, as set forth by D. 14-12-024, ADR is not a DR program. This position is consistent with that put forth in the April 8, 2018 ADR workshop and is supported by the position articulated in the February 17, 2017 joint IOU proposal on CC, where the IOUs stated that "Since DR Enabling Technology incentives are not a DR program on their own, the Joint

Utilities suggest that DR enabling technology programs could be determined to be out-of-scope for OP 8b."[4]

7. If a community choice aggregator or direct access provider develops its own critical peak pricing or real time pricing program, should the customers of these programs be eligible for Auto Demand Response incentives if the investor owned utility does not receive the resource adequacy credit for the load modifying demand response benefit? Does the amount the customer pays in distribution charges fairly compensate for the customer's participation? Should there be a carve-out/set-aside or a cap on the Auto Demand Response incentive budget for these customers? How would the Commission determine that carve-out/set-aside or cap?

PG&E does not recommend Community Choice Aggregator (CCA) or Energy Service Providers (ESP) critical peak pricing (CPP) or real-time pricing (RTP) programs become qualifying DR programs for ADR incentive. Some of the challenges this would create are listed below:

- It would be challenging for the ADR Program to monitor customer participation and performance of these programs in order to facilitate the payment of the ADR incentive;
- The ADR program would require a new process for the CCA/ESP to share customer information so that PG&E can operate these DR resources. It is unclear to PG&E if the CCA/ESP would be willing to share this information.

PG&E's position has been that ADR is not subject to Cost Causation; therefore, PG&E would continue to recover ADR costs and offer the ADR incentive to the CCA/ESP customers when they enroll in a PG&E DR Program that qualifies for ADR incentive. Since PG&E does not recommend for CCA/ESP CPP or RTP to be a qualifying DR program for ADR incentive, therefore there should be no carve out.

PG&E believes this question, along with many of the other questions on ADR, deserves a deeper level of discussion between all stakeholders in order to avoid unintended consequences such as but not limited to overcompensating ADR controls for specific technology and reducing

[4] D. 14-12-024, Ordering Paragraph 8b states "Once a direct access or community choice provider implements its own demand response program, the competing utility shall, no later than one year following the implementation of that program: i) end cost recovery from that provider's customers for any similar program and ii) cease providing the similar program to that provider's customers."

the number of DR Programs residential ADR customers can enroll in. These discussions should happen in the broader context of how ADR must evolve. Given the growing disconnect between ADR's existing design, today's third party DR market and consumer landscape, PG&E thinks the CPUC should consider a redesign of the ADR program, which may require evidentiary hearings, in order to jointly define objectives for the design of a future ADR Program.

8. How often should Auto Demand Response incentives be available to customers; i.e., frequency of incentives? Should the frequency be different for the residential and non-residential programs?

PG&E would propose using 7.5 years for all ADR control technologies, which is based on equipment amortization in PG&E's Demand Response Cost Effectiveness calculation for the ADR Program.

9. If a third-party provider uses a behavioral approach to encourage a customer to respond, i.e. text or email, should the customer control be eligible for Auto Demand Response incentives?

No, this approach would directly contradict the definition of the ADR control discussed in question 2 that defines *"the ability to receive an automated demand response signal to enable the customer to participate in a demand response event <u>without any manual customer intervention</u>."* A behavioral approach such as text or email requires customers to manually respond to these messages during DR events.

10. For demand response resource contracts external to the demand response portfolios and budget applications, should the Commission permit the customers of these contracts to receive auto demand response incentives for the controls? If the Commission determines it should allow these incentives, should such an allowance apply only to future procurements, or should it also apply to past procurements such as those with competitive bids that included all costs? If the Commission does not approve this policy, should the entire contract project site be ineligible for Auto Demand Response incentives including additional capacity in the battery storage or only the procured capacity resource and its controls? If the Commission determines it should permit these contracts to receive incentives, how should the Commission address the future funding issue since the 2018-2022 demand response budget for the incentives has already been authorized? If the Commission were to allow these customers to receive the incentives, should the Commission consider a carve-out/set-aside or a cap on the incentives?

PG&E believes that the assessment of whether a PG&E-administered DR external contract or solicitation to the DR portfolio should be added to the list of qualifying DR programs for ADR should be determined on a case-by-case basis with the development of a rigorous process in collaboration with stakeholders. This process should identify the principles that should drive the determination, such as but not limited to:

- Any ADR control that meets the ADR program requirements should be eligible for an ADR incentive, regardless if the ADR control is for HVAC, Lighting, battery or EVSE[5].
- The combination of contracts and enabling technology programs such as ADR should not lead to overcompensation to the customers.

Once the principles are identified, each external contract or solicitation should then be reviewed on a case by case basis. PG&E provides below some illustrations of why this is necessary:

- A solicitation external to the DR Portfolio may already require inclusion of all communication and control costs in the grid services offer. In that case, customers would be ineligible for the ADR incentive in order to avoid over compensating.
- In a situation where the contract external to the DR Portfolio requires the inclusion of some communication control but does not require OpenADR certification, the full calculation of the ADR incentive of $/ kW of load reduction potential would lead to over compensation. Determining a new formula for an ADR incentive should be carefully considered moving forward to address these types of scenarios. A potential pathway to explore would be to change the ADR incentive calculation by replacing the $ per kW of load reduction potential with an ADR incentive paid as a fixed

[5] ADR controls for HVAC, Lighting, battery or EVSE are eligible for ADR incentive for non-residential customers. PG&E is using the Collaborative Stakeholder Process to develop a list of ADR enabled control for residential customers that goes beyond Smart Thermostat.

amount (reflective for instance of the cost of the communication capability or of the cost to obtain the OpenADR certification).

PG&E believes that the existing ADR incentive calculation methodology of $/kW based on load reduction potential should be revised in the future.[6] This is why PG&E proposed using the Demand Response Emerging Technology Program (DRET) to evaluate alternative ADR incentive designs, such as:

- Paying a fixed amount to incentivize the adoption of the communication capability (if it does not already exist or is not already incentivized by another incentive program).
- Paying a fixed amount to incentivize the cloud communication to become OpenADR certified.
- Paying an upstream or a midstream incentive to the technology vendors or installers to make their control OpenADR certified.

PG&E will propose, for CPUC's approval, a new ADR incentive structure, with the goal to replace the current methodology ($/kW based on load reduction potential). Based on the findings from the DRET assessments, PG&E will recommend a new incentive methodology which may or may not be based on one of the three alternative design methods shown above.

PG&E recommends a case-by-case determination of whether a customer enrolled in an external PG&E-administered DR contract should be eligible for ADR incentive. PG&E also recommends that a process in collaboration with stakeholders be established in order to address how each case by case basis and future funding issue is going to be addressed.

11. Should the Commission require the Utilities to track the incremental load reduction provided by Auto Demand Response technologies and determine whether it fully covers the

[6] As PG&E pointed out in data request ED_075-Q03 and the CPUC ADR workshop on May 8, 2018, this calculation methodology for ADR incentive was developed more than 10 years ago, and the ADR control market has changed significantly since then. In addition, the ADR program was originally developed for large non-residential customers. Therefore, the original ADR conventions and design would require revisions to apply to Small/Medium Business and residential customers. To illustrate, a $/kW incentive calculation methodology requires the ADR program to develop a kW load reduction potential for each type of residential controls, which can be costly and time consuming.

additional cost of the Auto Demand Response control incentives allocated to demand response programs?

Yes, PG&E supports tracking the incremental load reduction provided by ADR control technologies. The IOUs have done load impact studies for the ADR Program in the past, and there has not been enough evidence that the ADR Program provides incremental load reduction that fully covers the additional cost of the ADR incentives allocated to the DR program. Due to the uncertainty of the ADR incremental load reduction benefit, PG&E did not include any incremental load impact associated with ADR incentives in its cost effectiveness calculation for non-residential CBP in its 2018-22 DR application (A. 17-01-012).

PG&E believes the primary role of the ADR Program is to increase the adoption of ADR enabled control technologies, therefore, the current $/kW ADR incentive structure needs to be revised in order to better align with the ADR Program objective.

12. Should the Commission provide additional guidance to the Utilities to create consistency between the calculation of Auto Demand Response incentive amounts applied to each program required for cost-effectiveness and what should that guidance entail? For example, should the Utilities apply incentive costs as capital costs to the *ex ante* load impacts (SDG&E's method), apply the incentives proportional to admin costs (SCE's method), or based on historical Auto Demand Response expenses (PG&E's method). See Attachment C.

PG&E supports consistency between IOUs in the calculation of ADR incentive amounts applied to each DR program that is required for cost-effectiveness (CE) calculation of the DR program. This is because it will help the CPUC to better align the CE results of the DR Programs among all IOUs. PG&E recommends a workshop among stakeholders such as the CPUC, IOUs and ORA to jointly develop a unified methodology for the calculation.

13. Should adding or enhancing Open Auto Demand Response capability to battery storage controls for participation in event-based demand response programs as a secondary service be approved as eligible to receive incentives? Is the incremental benefit provided by storage participating in demand response as a secondary service greater than the incremental cost of the incentive?

It is unclear to PG&E how the CPUC is defining the term "secondary service" in this question. If by secondary service CPUC means that the battery is committed to provide primary service (resource) to a DR contract external to the existing IOU's DR portfolio, then please refer to response for question 10 on PG&E's position, which also applies to this question.

14. If the Commission determines that the list of controls eligible to receive Auto Demand Response incentives should include Open Auto Demand Response capability to battery storage controls, what hardware/software costs should the incentives subsidize?

For non-residential customers, control for battery storage is already on the list of eligible controls for ADR incentives under PG&E's ADR Program. The battery storage controls, which include hardware/software costs, are eligible for ADR incentives. This would be similar to the hardware/software costs eligible for ADR incentive for other type of end uses such as HVAC and lighting.

For residential customer, PG&E is using the Stakeholder Collaborative Process to determine if an ADR control for a battery will be eligible for ADR incentives in the future.

15. Currently the Auto Demand Response program uses a $200 per kilowatt incentive level and calculates the incentive amount based on a building end use load shed test, with the customer eligible for incentives up to 75 percent of the project cost, if their building performs adequately. Would this be an appropriate incentive design for battery controls and if not, what other design would you propose? (e.g. fixed or flat rate per hardware device, etc.) Based on the exact costs identified above as appropriate, should the Commission adopt a maximum amount for battery storage control incentives, and why? (e.g. should the incentive be bounded by the incremental value the battery storage is providing for demand response above and beyond its primary load management services.)

PG&E separated question 15 to the following questions:

15-a) Currently the Auto Demand Response program uses a $200 per kilowatt incentive level and calculates the incentive amount based on a building end use load shed test, with the customer eligible for incentives up to 75 percent of the project cost, if their building performs adequately. Would this be an appropriate incentive design for battery controls

and if not, what other design would you propose? (e.g. fixed or flat rate per hardware device, etc.)

PG&E will use the $200/kW incentive level to calculate the incentive amount for both calculated and deemed ADR incentives. PG&E does not see the benefit of using a different incentive design for battery control compared to controls for other end use technologies. However, as PG&E answered in 10, we believe that the current $/kW ADR incentive structure needs to be revised in the future to avoid the potential of over compensating ADR controls.

15-b) Based on the exact costs identified above as appropriate, should the Commission adopt a maximum amount for battery storage control incentives, and why? (e.g. should the incentive be bounded by the incremental value the battery storage is providing for demand response above and beyond its primary load management services.)

PG&E's ADR Program does not allocate its budget by end use technologies, rather it's implemented on a first-come, first-served basis. PG&E does not plan to treat battery controls different from other ADR control technologies and does not see the benefit in adopting a maximum amount of ADR incentive for specific technologies.

16. Given that battery storage is eligible to receive incentives for controls from other publicly-funded programs, such as SGIP, what requirements should be in place to enable utilities reviewing incentive applications to prevent incentivizing the same equipment cost a second time?

PG&E notes that the CPUC is currently engaged in an extensive effort to improve the SGIP program. PG&E cautions that until that effort results in specific SGIP requirements, it is premature to draw conclusions about what the SGIP incentive covers for controls, and what the ADR incentive could incrementally cover with specific requirements, in order to avoid double compensation.

IV. MANAGING AND/OR MODIFYING THE TWO PERCENT RELIABILITY CAP

1. Explain whether the Commission should or should not consider adopting additional flexibility in the [RDRR] trigger by allowing its use anytime within the Warning stage[.]

It is PG&E's understanding based on CAISO Operating Procedure 4420 (Version 11.2 effective 9/18/2017) that the CAISO already has the ability to "Enable RDRRs in the market, globally or by region as needed, so as to make them available for dispatch through the market" at any time after issuing a Warning Notice.

PG&E notes that the language in Operating Procedure 4420 is less prescriptive than the language in the CAISO Tariff, General Dispatch Principles, Section 34.7 which states: "The CAISO may make Reliability Demand Response Resources eligible for Dispatch in accordance with applicable Operating Procedures either: (a) after issuance of a warning notice and immediately prior to a need for the CAISO to attempt to obtain assistance from neighboring Balancing Authorities or imports; (b) during stage 1, stage 2, or stage 3 of a System Emergency; or (c) for a transmission-related System Emergency." The language in General Dispatch Principles Section 34.7 is taken directly from Section A.4.l of the Reliability-Based Demand Response Settlement (CPUC Rulemaking 07-01-041, Phase 3) and is included as Appendix A to D.10-06-034. PG&E's current Base Interruptible Program (BIP) tariff identifies -- "CAISO market award or dispatch instruction by CAISO sub-LAP pursuant to CAISO Operating Procedure 4420" -- as a program trigger. BIP is the only RDRR program for which PG&E is the demand response program provider.

PG&E understands and shares the Commission's concern that customers may be incurring costs based on CAISO exceptional dispatch that could have been avoided if there was more flexibility in the RDRR trigger. However, it is unclear to PG&E based on the data available, whether a more flexible RDRR trigger could reasonably be expected to mitigate the need for exceptional dispatch and thereby reduce costs. PG&E recommends that the Commission work with the CAISO to determine the proper venue for stakeholder discussion and resolution of the discrepancy between the language in CAISO OP 4420 and CAISO Tariff

Section 34.7/RDRR Settlement Section A.4.l., in order to achieve the Commission's intent in D.10-06-034 as expressed on page 20 of the June 15, 2018 ACR Requesting Responses to Questions.

2. Explain whether the Commission should or should not consider adopting additional flexibility in the [RDRR] trigger by allowing its use in other stages *prior* to the Warning stage, such as Alert notice *and/or* Restricted Maintenance Operations.

PG&E does not believe that it would be appropriate to consider enabling RDRR into the market after issuance of a Restricted Maintenance notice. A Restricted Maintenance notification is not necessarily indicative of an imminent reliability event. From January 2016 through June 2018 the CAISO has issued 30 Restricted Maintenance Notifications and only 1 Alert, Warning or Emergency notification.

PG&E is open to discussing with the Commission, CAISO and DR Stakeholders the pros and cons of enabling RDRR into the market after issuance of an Alert Notice. Because the Alert Notice is issued the day prior to the projected reserves deficiency, stakeholders would need to discuss a number of potential operational issues related to the RDRR product being enabled by the CAISO into the day-ahead market after issuance of an Alert Notice. PG&E is currently piloting a day-ahead option for its BIP program.

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Respectfully Submitted,

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